Influence of Geochemical Processes on
the Geomechanical Responses of
Overburden Strata during CO\textsubscript{2} Storage in
Saline Aquifers

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Cover Illustration: Simplified schematic diagram of CO₂ plume in a storage reservoir interval.


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Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

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<th>Term</th>
<th>Description</th>
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<tbody>
<tr>
<td>2-D</td>
<td>Two-dimensional</td>
</tr>
<tr>
<td>CCS</td>
<td>Carbon capture and storage</td>
</tr>
<tr>
<td>CH₄</td>
<td>Methane</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>FC</td>
<td>Fluorinated gases</td>
</tr>
<tr>
<td>InSAR</td>
<td>Interferometric synthetic aperture radar</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied natural gas</td>
</tr>
<tr>
<td>N₂O</td>
<td>Nitrous oxide</td>
</tr>
<tr>
<td>PVT</td>
<td>Pressure, volume, temperature</td>
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</tbody>
</table>
Acknowledgments

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EXECUTIVE SUMMARY
Saline aquifers have been identified as types of desirable geologic formations suitable for storage of carbon dioxide (CO₂) in large amounts. While the impermeable caprock layer(s) in the overburden provides the primary trap for injected CO₂, other trapping mechanisms such as solubility, residual, ionic or mineral trapping help contribute to CO₂ storage. Geochemical reactions alter the petrophysical properties in the target reservoir, and may have an influence on the reservoir storage capacity. When CO₂ is injected for long periods of time, it changes the fluid pressures and overburden geomechanical response.

In this study, coupled multiphase fluid flow and geomechanical modeling with geochemical processes was performed to simulate long-term (1,000 years), large-scale injection of CO₂ (up to 10 million metric tons per year) into a deep saline aquifer, to investigate the influence of geochemical processes on the geomechanical response of overburden during long-term CO₂ injection. Geochemical modeling results from this study show that geochemical processes such as mineral dissolution and precipitation have very little influence on reservoir rock porosity at the reservoir scale. Results from the coupled fluid flow and geomechanics models with geochemical reactions for large-scale CO₂ injection scenarios indicate that the inclusion of geochemical reactions in the geomechanical models have a very little influence on the computed vertical ground displacements during injection and post-injection periods. Modeling results show that the pressure increases and ground displacements caused due to CO₂ injection decay with time during the post-injection period.

Thus, the study findings are that geochemical interactions have no significant impact on geomechanical response at the reservoir scale. It should be noted, however, that the impacts of geochemistry on geomechanical response at the local scale, such as in faults or fractures that are found in a caprock layer, were not addressed in this study.
1. INTRODUCTION

1.1 BACKGROUND

Over the past three decades, global warming has become more apparent, with more than two-thirds of Earth’s mean surface temperature increasing. The primary source for such radical change is the increase in the atmospheric concentration levels of greenhouse gases. Greenhouse gases absorb and emit infrared radiations, which cause an increase in atmospheric temperature. Based on global emission records for the past three decades, it has been reported that carbon dioxide (CO₂) is the major contributor (9–26%) to global warming in addition to other greenhouse gases such as methane (CH₄), nitrous oxide (N₂O), and fluorinated gases (Kiehl and Trenberth, 1997).

CO₂ is considered a major contributor to greenhouse gas emissions, with estimates of about 38 GtCO₂/yr in 2010, which accounts for about 76% of the total anthropogenic greenhouse gases emitted in 2010 (IPCC, 2014). CO₂ emissions have been reported to be continuously rising by about 1–2% in recent years (IPCC, 2014). Scientific studies have indicated that if the cumulative emissions in the next three decades are kept below 1,500 billion tonnes, then the average global rise in temperature can be limited to two degrees Celsius above pre-industrial levels (Olivier et al., 2012). Carbon capture and storage (CCS) is one of several mitigation efforts deployed worldwide to reduce atmospheric CO₂.

1.2 GEOLOGIC STORAGE OF CARBON DIOXIDE

CCS involves the process of capturing CO₂ otherwise released into the atmosphere from various sources, such as high CO₂ natural gas fields, liquefied natural gas (LNG), mineral processing plants, or coal-fired power stations (CO2CRC, 2008). CO₂ is then transported through pipelines and injected into deep geological formations such as depleted oil and gas fields, coal seams, or saline formations for long-term storage. Saline aquifers are considered to be suitable for large volumes of CO₂ storage (Bachu, 2000; Bradshaw et al., 2002; Eke et al., 2011; Liu et al., 2011b; Gaus et al., 2008). Saline aquifers are deep sedimentary formations, saturated by formation water with salinity above the permissible limits for water that is useful for human consumption, agricultural or industrial use. Geological storage of CO₂ in saline aquifers would generally occur at supercritical conditions, which exist in deep aquifers where CO₂ has a high density (Nghiem et al., 2004). Under such conditions, the same mass of CO₂ occupies less volume enabling more CO₂ storage. Different trapping mechanisms, such as structural trapping, residual gas trapping, solubility trapping, and mineral trapping contribute to CO₂ storage in saline aquifers (Gunter et al., 1993; Bachu et al., 1994; Perkins and Gunter, 1995; Ennis-King and Patterson, 2001; Hotlz, 2002; Flett et al., 2004). Industrial-scale projects in deep saline aquifers at the Sleipner site in the North Sea and the In Salah site in Algeria have demonstrated the containment of injected CO₂ (Arts et al., 2008; Hosa et al., 2010).

1.3 CARBON STORAGE ISSUES

While the impermeable caprock layer(s) in the overburden provides the primary trap for injected CO₂, other trapping mechanisms such as solubility, residual, ionic, or mineral trapping help contribute to CO₂ storage security. Depending on the nature and scale of geochemical reactions, CO₂ may interact with formation water, reservoir rock, and overburden caprock layer(s). These interactions may alter the rock properties influencing CO₂ injectivity, storage capacity, and seal
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integrity. Processes such as dissolution or mineral precipitation may have significant influence on the storage capacity during long-term CO2 injection into a deep saline aquifer. Some impacts of geochemical reactions on the injectivity and storage of CO2 are given below (Czernichowski-Lauriol et al., 2006):

- Mineralogical reactions occur due to thermodynamic, kinetic, and transport processes, which can result in the modification of formation or caprock properties such as porosity and permeability. These changes can influence the amount of CO2 injection and may also lead to caprock leakage.
- Mineral dissolution around the injection well increases injectivity
- Dissolution of minerals in the caprock may lead to leakage pathways and may impact the sealing efficiency of overburden caprock layer(s)
- Mineral precipitation hinders the flow making it difficult to maintain high injection rates
- Mineral precipitation also induces self-sealing in caprock fractures

Numerous studies have been performed to address several issues related to the long-term storage of CO2 and different CO2 trapping mechanisms in deep saline aquifers (Bachu et al., 1994; Bachu, 2000; Basbug et al., 2005; Doughty et al., 2004). However, limited emphasis has been placed on estimating the geomechanical response caused due to large-scale CO2 injection into a saline reservoir. Geomechanical issues related to large-scale CO2 injection in saline aquifers were investigated in the past using coupled flow and geomechanical models (Rutqvist et al., 2008; Tran et al., 2009; Morris et al., 2011; Vilarrasa et al., 2011; Rutqvist, 2011; Goodarzi et al., 2012).

The geomechanical response associated with time-dependent geochemical reactions may influence the integrity of caprock layer and long-term fate of injected CO2. When CO2 is injected for long periods of time, it changes the fluid pressures and overburden response. The changes in pressure, temperature, and mineral compositions due to geochemical interactions between acidified water and formation rock may lead to variation in stress changes and ground displacements (Czernichowski-Lauriol et al., 2006). Excessive surface deformation can lead to failure of well casings, pipelines, and other underground utilities (Khakim et al., 2012).

In addition to coupled fluid flow and geomechanical modeling of CO2 storage, field monitoring studies using GPS and interferometric synthetic aperture radar (InSAR) technologies are being performed to measure ground surface deformations with a precision in the sub millimeter range over large areas (Khakim et al., 2012). Such ground monitoring technologies have been used in the past at the Belridge and Lost Hills oil field in California, and the In Salah CO2 sequestration site located in Krechba, Algeria (Patzek and Silin, 2000, 2001; Morris et al., 2011; Mathieson et al., 2011). Although ground monitoring technologies provide great insight into the magnitudes and patterns of ground displacements, and flow behavior, it is important to develop advanced modeling methods as the time-scale for evaluation of storage safety is usually in terms of hundreds and thousands of years. Such long-term numerical studies require the coupling between fluid flow, geochemical reactions, and potential implications of geomechanical stability (Kvamme and Liu, 2009). In this study, coupled multiphase fluid flow and geomechanical modeling with geochemical processes were performed to investigate the geomechanical response in the reservoir and overburden layers caused by large-scale injection of CO2 into a deep saline aquifer.
1.4 RESEARCH OBJECTIVES

The primary objective of this research work is to investigate the influence of geochemical processes on the geomechanical response of the overburden caused by long-term, large-scale CO₂ injection. The study aims at developing a basic understanding of flow and pressure distribution during and after CO₂ injection and its impact on vertical displacements. This study will also help determine the region impacted by changing pressure or saturation during or after CO₂ injection. A numerical model coupled with geomechanics and geochemical processes was used to investigate the multiphase fluid flow and multi-component transport of CO₂ and brine in response to CO₂ injection into an idealized multi-layer geologic formation, indicative of sedimentary basins.
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2. BACKGROUND

2.1 CO2 TRAPPING MECHANISMS

Tight, impermeable caprock layer(s), which overlay the target aquifer, provide the primary trap for injected CO2 into a deep saline aquifer. In addition to tight, impermeable caprock layer(s) in the overburden, several other trapping mechanisms in saline/brine aquifers that occur over a period of time contribute to the storage of CO2. Some of these trapping mechanisms in saline aquifers include structural/stratigraphic, residual, hydrodynamic, solubility, ionic, and mineral trapping (Gunter et al., 1993; Bachu et al., 1994; Perkins and Gunter, 1995; Ennis-King and Patterson, 2001; Hotlz, 2002; Flett et al., 2004).

The flow behavior of CO2 in deep saline aquifers was demonstrated by a few long-term, large-scale field projects (Arts et al., 2008; Hosa et al., 2010; Michael et al., 2010; Morris et al., 2011). For example, migration of CO2 at different times (at different trapping levels) was investigated at the Sleipner site in the central North Sea (Arts et al., 2008) and at the In Salah site in Algeria (Hosa et al., 2010). Several other numerical modeling studies were also performed to understand the flow behavior of CO2 due to different trapping mechanisms at different time scales (Bachu et al., 1994; Bachu, 2000; Basbug et al., 2005; Doughty et al., 2004; Fang et al., 2010). The trapping mechanisms may influence CO2 migration in the subsurface over a period of time. More details on these trapping mechanisms are presented in following sections.

2.1.1 Structural/Stratigraphic Trapping

When CO2 is injected into a deep saline aquifer, CO2 gets physically trapped as a free gas or supercritical fluid into subsurface geologic media or geologic structures (Bachu, 2007; Nghiem et al., 2009). The free gas (immiscible CO2) rises to the top until it reaches a tight, impermeable caprock layer, and some part of the injected CO2 dissolves into formation water becoming CO2-rich brine (Bachu et al., 1994). The free-phase, immiscible CO2 which rises upwards to the top of the aquifer due to buoyancy (due to differences in the density of CO2 and formation water) gets physically trapped in structural or stratigraphic traps (Bachu et al., 2007; CO2CRC, 2008). Typical traps include anticlinal structures, folds, faults, salt domes, and stratigraphic traps such as depositional pinch outs (CO2CRC, 2008).

2.1.2 Residual Trapping

The free-phase, immiscible CO2 also gets physically trapped and becomes immobile in the porous geologic media by capillary forces. This is known as residual-gas trapping (Basbug et al., 2005; Bachu et al., 2007). At the tail of the migrating CO2 plume, imbibition processes are dominant as the formation water (wetting-phase) displaces the immiscible CO2 (non-wetting phase). Capillary pressure forces become dominant when the concentration of the CO2 falls below a certain level. The dominant capillary pressure forces trap the CO2, thus leaving a trace of residual, immobile CO2 behind the plume as it migrates upward (Ennis-King and Paterson, 2002; Holtz, 2002; Flett et al., 2004; Juanes et al., 2006).

2.1.3 Hydrodynamic Trapping

Generally, fluid flow velocities are low in saline aquifers. For this reason, the injected CO2 in the subsurface may take long periods of time (up to millions of years) before it reaches the surface due to different trapping mechanisms occurring in the migration pathway (Bachu et al., 2007;
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CO2CRC, 2008; Fang et al., 2010). This geological time-scale trapping process of injected CO2 in the subsurface is known as hydrodynamic trapping (Bachu et al., 1994; Bachu, 2007; CO2CRC, 2008; Fang et al., 2010).

2.1.4 Solubility and Ionic Trapping

In addition to the physical trapping of injected CO2, chemical trapping occurs when CO2 is dissolved in the formation water. Diffusion, dispersion, and convection processes help injected CO2 to mix and dissolve in formation water. CO2 dissolution into the formation water is referred to as solubility trapping (Bachu, 2007; Koide et al., 1992). A weak carbonic acid is produced when CO2 dissolves in the formation water (solubility trapping), which rapidly dissociates into bicarbonate ions and formation of soluble complexes (ionic trapping) (Eke et al., 2011; Ortoleva et al., 1998; Xu et al., 2001). The reaction steps for CO2 dissolution and subsequent dissociation of weak carbonic acid into carbonate species are shown in Equations 1 and 2 below:

\[
\text{CO}_2 (g) + \text{H}_2\text{O} = \text{H}_2\text{CO}_3 \quad (\text{solubility trapping})
\]

\[
\text{H}_2\text{CO}_3 = \text{H}^+ + \text{HCO}_3^- \quad (\text{ionic trapping})
\]

Formation temperature, pressure, water salinity, and time-scale of geological storage are important factors that contribute to the solubility or dissolution of CO2 (CO2CRC, 2008; Fang et al., 2010). CO2 solubility increases with an increase in fluid pressure, and decreases with an increase in formation temperature and water salinity (CO2CRC, 2008; Fang et al., 2010). When CO2 dissolves in the formation water, the density of CO2-enriched brine increases and the saturated brine sinks to the bottom of the reservoir. The time-scale for complete dissolution is predicted to occur on a scale of hundreds to thousands of years (Ennis-King and Paterson, 2002).

2.1.5 Mineral Trapping

The dissolution of CO2 in the formation water decreases the pH of the brine (i.e., increases acidity), and further geochemical reactions occur between CO2-enriched brine and the rock matrix to form stable carbonate materials such as calcite (CaCO3) (CO2CRC, 2008; Gaus et al., 2008; Eke et al., 2011). This process is known as mineral trapping. Some of the geochemical reactions associated with dissolution of primary rock minerals, and dissolved bicarbonate ions reacting with divalent cations (such as calcium (Ca²⁺), magnesium (Mg²⁺), and iron (Fe²⁺)) to precipitate new carbonate minerals are shown in Equations 3 through 6 below (Xu, 2001):

\[
\text{Ca}^{2+} + \text{HCO}_3^- = \text{CaHCO}_3^+
\]

\[
\text{HCO}_3^- + \text{Ca}^{2+} \cdot = \text{CaCO}_3 \text{ (solid)} + \text{H}^+
\]
HCO$_3^-$ + Mg$^{2+}$ = MgCO$_3$ (solid) + H$^+$  \hspace{1cm} (5) \\
HCO$_3^-$ + Fe$^{2+}$ = FeCO$_3$ (solid) + H$^+$  \hspace{1cm} (6)

It is believed that many of these newly precipitated carbonate minerals, such as calcite (CaCO$_3$), dolomite [CaMg(CO$_3$)$_2$], and siderite (FeCO$_3$) remain stable for significant time periods, enhancing CO$_2$ permanence (Gunter et al., 1993; Bachu et al., 1994; Perkins and Gunter, 1995; CO2CRC, 2008). It is also reported that silicastic reservoirs, especially the calcium, magnesium, or iron-rich reservoirs are more favorable for mineral trapping compared to other carbonate reservoirs (CO2CRC, 2008). Mineral trapping is formation specific and mainly depends on factors such as mineralogical composition of geologic formation, chemical composition of formation brine, formation temperature and pressure, and fluid flow rate (CO2CRC, 2008; Gunter et al., 2004). Reservoir temperature also has an influence on the flow behavior of CO$_2$ (Lindeberg and Wessel-Berg, 1997). In any geological storage site, the injected CO$_2$ will ultimately be trapped by a number of mechanisms as shown in Figure 1. With increasing time, the dominant storage mechanisms will change, and typically the storage security also increases. Figure 2 shows a simple representation of the change of dominant trapping mechanisms and increasing CO$_2$ storage security with time.

**Figure 1: CO$_2$ trapping mechanism.**
2.2 INFLUENCE OF MINERAL TRAPPING ON POROSITY AND PERMEABILITY

When a fluid is injected into the reservoir, the injected fluid displaces the formation water depending on rock properties and the fluid properties of connate water and injected fluid (van der Meer, 2005). When supercritical CO₂ is injected into an aquifer, it rises to top of the aquifer and moves through the pore structures of the formation rock (due to low density and viscosity) (van der Meer, 2005). Interaction between CO₂, brine, and formation rock may have an influence on porosity and permeability of the formation rock (Luquot and Gouze, 2009). These geochemical reactions depend on several factors such as reservoir temperature, pressure, water salinity, rock mineralogy and texture, fluid injection rates, and time-scale of geological storage (CO2CRC, 2008; Fang et al., 2010; van der Meer, 2005).

The porosity and the permeability near the injection region increases due to rapid dissolution of carbonates at high pressures, and decreases further from the well along the flow direction due to carbonate precipitation (van der Meer, 2005). This is especially the case for carbonate reservoirs, but for sandstone reservoirs the carbonate precipitation may be minimal. Excess dissolution of rock and CO₂ interaction with overburden caprock materials may alter the caprock properties and create high-permeability zones (e.g., in carbonates) and could elevate the risk of CO₂ leakage (van der Meer, 2005). While the excess rock dissolution increases porosity, permeability, and injectivity, it could also lead to wellbore instability and subsidence if the integrity of formation rock is compromised (Luquot and Gouze, 2009). Also, it is reported that the precipitation of dissolved CO₂ into new carbonate materials (due to geochemical reactions) may significantly reduce the porosity, permeability, and cause serious injectivity issues (Luquot and Gouze, 2009).
3. FLUID FLOW, GEOMECHANICAL AND GEOCHEMICAL MODELING OF CO₂ SEQUESTRATION IN SALINE AQUIFERS

In this study, numerical models were constructed to investigate the influence of geochemical processes on the fluid flow behavior and overburden geomechanical response due to CO₂ injection. These numerical models consider:

1. Vertical migration of CO₂ due to buoyancy towards the impermeable caprock
2. Dissolution of CO₂ in formation brine
3. Mineral dissolution and precipitation through the interaction between dissolved CO₂ and formation rock
4. The changes in pressure and mineral compositions due to geochemical interactions between acidified water and formation rock
5. Variation in stresses and deformations due to fluid flow and geochemical reactions

3.1 MODELING OF CO₂-BRINE-ROCK INTERACTION

When CO₂ is injected into a saline aquifer, some of it dissolves in the aqueous phase. Reservoir modeling, generally assumes that the gas and aqueous phase exist in a thermodynamic equilibrium (Nghiem et al., 2004) in each grid block so that the simulations are tractable. Such equilibrium can be attained when the residence time in a grid block is long enough for diffusion of CO₂ in the brine. In this study, the Peng-Robinson equation of state was used to calculate the pressure, volume, and temperature (PVT) properties of CO₂ (Peng and Robinson, 1976).

Solubility of CO₂ in the aqueous phase is calculated by using Henry’s Law, where the constants depend on pressure, temperature, and salinity (Li and Nghiem, 1986). Geochemical reactions in a saline formation occur between components in the aqueous phase, and also between components in the aqueous phase and minerals. Intra-aqueous reactions are rapid when compared to geochemical reactions taking place during mineral dissolution and precipitation. Mineral dissolution and precipitation are rate-dependent reactions. The rate law used to model the mineral dissolution and precipitation can be found in Bethke (1996). The reaction rate for mineral dissolution and precipitation is a function of reactive surface area for a mineral, rate constant of mineral reactions, chemical equilibrium constant for mineral reaction, and activity product of mineral reactions (CMG, 2012; Nghiem et al., 2004). The activity product is a quantity that determines whether a substance dissolves or precipitates in a given solution (CMG, 2012). The activity product was internally calculated in the computational program (CMG, 2012). Mineral dissolution and precipitation depends on the magnitude of the saturation index. The ratio of activity product of mineral reactions and chemical equilibrium constant for mineral reactions is called the saturation index of the mineral reaction (CMG, 2012). For mineral dissolution to occur, saturation index should be greater than 1, and for mineral precipitation to occur the saturation index is less than 1 (CMG, 2012).

3.2 COUPLED MULTIPHASE FLUID FLOW AND GEOMECHANICS MODEL

In this study, CMG-GEM was used to model multiphase fluid flow, which is based on a finite difference approach. CMG-GEM is a commercially available advanced compositional simulator developed by Computer Modeling Group (CMG, 2012). The geomechanics module (based on finite element method) of CMG-GEM was used to incorporate geomechanical calculations.
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The basic equations for reservoir fluid flow consist of mass balance equations, Darcy’s law, and phase equilibrium models. Besides Darcy’s law which governs the fluid flow in the reservoir, transport phenomenon such as dispersion and diffusion also contributes to the movement of components in the aqueous phase (Tran et al., 2009). The material-balance finite difference constitutive equations for different components in the gaseous and aqueous phase can be found in Tran et al. (2009). This work in this technical report used coupled fluid flow and geomechanical models that include geochemical reactions.

3.3 MODELING DETAILS

In this study, two-dimensional (2-D), radially symmetric, multiphase, and single-porosity models were constructed to study the influence of geochemical changes on the geomechanical response of the overburden over a long time period (1,000 years). The model geometry consists of an overburden layer, a tight caprock layer, a sandstone reservoir layer and an underburden layer to represent a hypothetical CO₂ storage site. Geochemical reactions and geomechanical properties were assumed as described in Section 4. Figure 3(a) shows the idealized geologic column considered for the hypothetical CO₂ injection site. Figure 3(b) shows the schematic diagram of the numerical model considered in this study.

Two different axisymmetric models with the same geometry were constructed to determine the influence of geochemical reactions or processes on reservoir properties (such as porosity and permeability) and the geomechanical response of the overburden. These two models are: 1) a geochemical model to determine the influence of geochemical reactions on hydrologic properties such as porosity and permeability, and 2) a coupled fluid flow and geomechanics model with geochemical reactions to determine the influence of geochemical reactions on the geomechanical response of the system as described in Section 4. The axisymmetric models consist of 90 grid-blocks in the radial direction and 13 layers in the z-direction. Figure 4 shows the model geometry. A radial length of 164,042 ft (50,000 m) was considered in these models. Such a large lateral extent was chosen to ensure that the boundary conditions have minimal effect on the geomechanical modeling results. Reservoir thickness was assumed to be 1,620 ft (494 m). The porosity and permeability of the reservoir in both models were assumed to be 20% and 100 millidarcies (mD), respectively. The bottom boundary of these models was constrained and lateral boundaries were set on rollers. The grid block volumes of boundary elements in the reservoir layer were modified with large volume modifiers to model the infinitely large extent of the reservoir layer.

A hypothetical injection scenario was assumed for both models. CO₂ was injected at a primary rate constraint of 0.402 million short tons per year (0.365 million metric tonnes per year or 1,000 metric tonnes per day) for 25 years with a secondary bottomhole pressure constraint of 4,351 psi (30,000 kPa). The initial average reservoir pressure was assumed to be 3,340 psi (23,026 kPa) in the model. The formation temperature at the center of reservoir was assumed to be 119.78°F (48.77°C). The simulations were carried out for 1,000 years (25 years of CO₂ injection and 975 years of post-injection). These models were used to determine the extent of CO₂ migration during injection and post-injection period. In both models, geochemical processes such as mineral dissolution/precipitation, the change in rock properties due to mineral reactions, and the pressure changes due to CO₂ transport and dissolution were investigated. Figure 5 shows the
assumed relative permeability curves used in this study (Tran et al., 2009). Modeling assumptions made in this study are given below.

1. The reservoir layer is homogeneous and isotropic
2. Injection well components do not react with CO₂. Issues related to corrosion and other chemical issues affecting well completion and surface facilities are not addressed
3. Injected CO₂ is free from impurities such as H₂S, SO₃, NOₓ, and O₂. These impurities can dissolve into brine, which is believed to affect pH and oxidation-reduction potential of brine (Jun et al., 2013)
4. The saline aquifer does not consist of any organic compounds. The presence of organic compounds can influence dissolution and precipitation (Yang et al., 2011)
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO$_2$ Storage in Saline Aquifers

(a) Idealized geologic column

(b) Schematic diagram of the model

Figure 3: Idealized geologic column and problem definition.
Figure 4: Vertical cross section of model layers.

Figure 5: Assumed relative permeability curves.
4. RESULTS OF FLUID FLOW, GEOMECHANICAL, AND GEOCHEMICAL MODELING

4.1 MODEL 1: GEOCHEMICAL MODEL

A geochemical model was constructed to investigate the influence of geochemical reactions on rock properties such as porosity and permeability. The intra-aqueous chemical-equilibrium reactions, mineral reactions, and volume fractions considered in the model are shown in Figure 6. A simple mineralogy (with 3 minerals) was selected in this numerical example to demonstrate that the geochemical model is able to simulate geochemical reactions caused by CO$_2$ injection. In this study, the total surface area of each mineral per unit volume was assumed to be 1,000 m$^2$/m$^3$ as reported in the literature (Nghiem et al., 2004; Xu et al., 2001). Table 1 provides the mineral dissolution/precipitation kinetic data that were used for the calculation of reaction rate constants at reservoir temperature. These values are in the same range as those values reported in the literature (Nghiem et al., 2004; Xu et al., 2001). The reactive surface area changes due to mineralization and the reaction rate constants were computed at every time step. The salinity in the model was varied from 1 ppm (top of the model) to 195,000 ppm (base of the model) with depth as shown in Figure 7. These values of salinity are in the range of salinity values reported in the published literature (Gunter et al., 2000; Birkholzer et al., 2009; Bachu and Bennion, 2009; Zhou et al., 2010; Micheal et al., 2010; Heinemann et al., 2012).

Figure 6: Intra-aqueous chemical-equilibrium and mineral reactions.
Table 1: Mineral dissolution/precipitation reaction data (Xu et al., 2001; Nghiem et al., 2004; Johnson et al., 2004)

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Chemical Composition</th>
<th>Log (rate constant) (mol/m²/s) @ 25 °C</th>
<th>Computed Reactive surface (m²/m³)</th>
<th>Activation Energy (J/mol)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaolinite</td>
<td>Al₂Si₂O₅(OH)₄</td>
<td>-13.0</td>
<td>200</td>
<td>62,760</td>
</tr>
<tr>
<td>Calcite</td>
<td>CaCO₃</td>
<td>-8.79588</td>
<td>300</td>
<td>41,870</td>
</tr>
<tr>
<td>Anorthite</td>
<td>CaAl₂Si₂O₈</td>
<td>-12.0</td>
<td>300</td>
<td>67,830</td>
</tr>
</tbody>
</table>

Reaction rate constants corresponding to mineral dissolution and precipitation at the reservoir temperature are calculated internally within the computer code based on the values of the rate constants at the given reference temperature. These values are in the same range as those values reported in the literature (Nghiem et al., 2004; Xu et al., 2001).

Modeling results show that when CO₂ is injected into the target saline reservoir, CO₂ migrates to the top of the reservoir and is trapped by the overlying tight, low-permeability caprock layer. As CO₂ dissolves in the aqueous phase, density of brine increases and the aqueous CO₂ flows to the bottom of the reservoir. Modeling results show that the evolution of CO₂ saturation is consistent with the migration of the CO₂ plume. Modeling results also show that water saturation decreases initially and then increases, thus indicating the lateral migration of the CO₂ plume and the progressive dissolution of injected CO₂ in the formation brine. The pH value of formation brine changes from 7.05 (initially) to 4.84 (at the end of 25 years of injection) due to CO₂ dissolution in brine as shown in Figure 8. In the regions where high dissolution of CO₂ takes place, acidic...
nature of brine increases (pH~5) and mineral dissolution occurs. Precipitation of calcite and kaolinite occurs in the neighboring zone (pH > 6) that surrounds mineral dissolution.

![Figure 8: pH profile at the end of CO₂ injection (25 years).](image)

### 4.1.1 Mineral Dissolution and Precipitation

Regions of high CO₂ dissolution in brine have lower pH value, thus leading to acidic conditions. This leads to dissolution of minerals such as calcite and anorthite. Anorthite is a non-carbonate, calcium-rich mineral, whose dissolution provides calcium ions to the formation brine. With time, the calcium ions (Ca²⁺) in the formation brine react with available bicarbonate ions in brine to precipitate calcium carbonate (CaCO₃) or calcite. In addition to calcium ions (Ca²⁺), aluminum ions (Al³⁺) and silicate ions (SiO₂) react to precipitate kaolinite. Figure 9 shows the changes in mole concentration of calcite, anorthite, and kaolinite after 1,000 years. The sign convention used in the computer model is that the amount of mineral dissolution (gmole) is negative and mineral precipitation (gmole) is positive.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure 9: Molar concentration after 1,000 years.
Due to mineral dissolution and precipitation, rock porosity changes with time, such that \( \Theta_{\text{new}} = \Theta_{\text{old}} + \frac{V_p}{V_t} \), where \( V_p \) is the volume of mineral precipitated (negative for dissolution) and \( V_t \) is total volume in a grid block. The change in permeability with porosity can be computed using the Kozeny-Carmen equation. Figure 10 shows the change in porosity due to geochemical reactions after 1,000 years (25 years of CO\(_2\) injection and 975 years of post-injection). Modeling results show that the change in porosity due to geochemical reactions is not significant (~0.4% as shown in Figure 10), which translates to a 2% change in the original porosity. At the field site, knowing the appropriate reaction rate to use can be highly uncertain. Thus, the reaction rate constants were adjusted upwards to see if they might have an impact on rock porosity. The revised reaction rate constants are shown in Table 2. Based on the revised reaction rate constants, the maximum change in the computed porosity was observed to be 6% after 1,000 years as shown in Figure 11. This change in porosity translates to a 30% change of the original porosity. The porosity change with time is shown in Figure 11. This change in porosity can be considered small. The change in porosity and permeability in a selected block close to the injection well is shown Figure 12(a) and 12(b), respectively. The mineral dissolution and precipitation kinetic data shown in Table 1 and Table 2 are same.

Figure 10: Reservoir porosity after 1,000 years.
Table 2: Mineral reaction data

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Chemical Composition</th>
<th>Log (rate constant) (mol/m²/s) @ 25 °C</th>
<th>Assumed Log (rate constant) (mol/m²/s) @ 25 °C</th>
<th>Computed Reactive Surface (m²/m³)</th>
<th>Assumed Reactive Surface (m²/m³)</th>
<th>Activation Energy (J/mol)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaolinite</td>
<td>Al₂Si₂O₅(OH)₄</td>
<td>-13.0</td>
<td>-10.0</td>
<td>200</td>
<td>2000</td>
<td>62,760</td>
</tr>
<tr>
<td>Calcite</td>
<td>CaCO₃</td>
<td>-8.79588</td>
<td>-8.79588</td>
<td>300</td>
<td>300</td>
<td>41,870</td>
</tr>
<tr>
<td>Anorthite</td>
<td>CaAl₂Si₄O₈</td>
<td>-12.0</td>
<td>-10.0</td>
<td>300</td>
<td>300</td>
<td>67,830</td>
</tr>
</tbody>
</table>

Figure 11: Change in porosity with time due to mineralization.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure 12: Change in porosity and permeability with time due to mineralization.

(a) Change in porosity in a selected block close to the injection well

(b) Change in permeability in a selected block close to the injection well
4.2 MODEL 2: COUPLED FLUID FLOW AND GEOMECHANICS MODEL WITH GEOCHEMICAL REACTIONS

A coupled fluid flow and geomechanics model was constructed to investigate the behavior of fluid flow and ground response with the inclusion of geochemical reactions. Geomechanical calculations in CMG-GEM are based on an iterative coupling method as described in the literature (CMG, 2012; Tran et al., 2009). The fluid flow module in CMG-GEM considers CO₂ dissolution and geochemical reactions to determine changes in fluid pressure with time. The geomechanical calculations such as change in stresses and deformations are computed at every time step. A constant elastic modulus of 5.8e+06 psi (40 GPa) and a Poisson’s ratio of 0.25 was used for all rock formations. These geomechanical properties are similar to values reported at the Mount Simon Sandstone reservoir. Figure 13 shows the assumed initial mineral volume percentages (%) in the reservoir. The mineralogy and chemical composition are similar to Mount Simon Sandstone reservoir, and consistent with published literature (Liu et al., 2011a). Table 3 provides the mineral dissolution/precipitation kinetic data that were used for the calculation of reaction rate constants at reservoir temperature. The reaction rate constants are calculated internally in the geochemical module in CMG-GEM. A formation temperature of 119.78 °F (48.77 °C) was assumed at the center of the reservoir due to a thermal gradient. The reservoir temperature directly affects the kinetics of geochemical reactions that occur during CO₂ injection. For the coupled fluid flow and geomechanical models with geochemical reactions, the chemical composition was extended to include 7 minerals with higher silica content to define the realistic rock composition. Only three minerals were considered in the geochemical models to demonstrate that the geochemical models used in the study are able to simulate the geochemical reactions caused by CO₂ injection.

Figure 13: Mineral volumes in the reservoir.
Table 3: Mineral dissolution/precipitation reactions (Palandri and Kharaka, 2004; Johnson et al., 2004)

<table>
<thead>
<tr>
<th>Mineral</th>
<th>Chemical Composition</th>
<th>Molar Weight (g/mol)</th>
<th>Density (kg/m³)</th>
<th>Log K&lt;sub&gt;meq&lt;/sub&gt; (50 °C)</th>
<th>Log (rate constant) (mol/m²/s) @ 25 °C</th>
<th>Reactive Surface Area (m²/m³)</th>
<th>E (J/mol)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaolinite</td>
<td>Al₃Si₂O₅(OH)₄</td>
<td>258</td>
<td>2,594</td>
<td>5.4706</td>
<td>-13.0</td>
<td>17,600</td>
<td>62,760</td>
</tr>
<tr>
<td>Calcite</td>
<td>CaCO₃</td>
<td>100</td>
<td>2,710</td>
<td>1.3560</td>
<td>-8.79588</td>
<td>88</td>
<td>41,870</td>
</tr>
<tr>
<td>Anorthite</td>
<td>Ca₆Al₂Si₂O₈</td>
<td>116</td>
<td>4,047</td>
<td>23.0603</td>
<td>-12.0</td>
<td>88</td>
<td>67,830</td>
</tr>
<tr>
<td>Dolomite</td>
<td>CaMg(CO₃)₂</td>
<td>184</td>
<td>2,864</td>
<td>1.6727</td>
<td>-9.22180</td>
<td>88</td>
<td>41,870</td>
</tr>
<tr>
<td>Illite</td>
<td>Mg₀.₂₅K₀.₆Al₂.₃Si₃.₅O₁₂H₂</td>
<td>384</td>
<td>2,763</td>
<td>7.4855</td>
<td>-14.0</td>
<td>26,400</td>
<td>58,620</td>
</tr>
<tr>
<td>Quartz</td>
<td>SiO₂</td>
<td>60</td>
<td>2,648</td>
<td>-3.6285</td>
<td>-13.9</td>
<td>7,128</td>
<td>875,500</td>
</tr>
<tr>
<td>K-feldspar</td>
<td>KAlSi₃O₈</td>
<td>278</td>
<td>2,655</td>
<td>-0.3439</td>
<td>-12.0</td>
<td>176</td>
<td>67,830</td>
</tr>
</tbody>
</table>

Reaction rate constants corresponding to mineral dissolution and precipitation at the reservoir temperature are calculated internally within the computer code based on the values of the rate constants at the given reference temperature. These values are in the same range as those values reported in the literature (Nghiem et al., 2004; Xu et al., 2001).

### 4.2.1 Geochemical Response

The computed amount of mineral dissolved and deposited over a period of 1,000 years is shown in Figure 14. The dissolution of minerals such as dolomite, calcite, annite, illite, and K-feldspar takes place initially at lower pH values. Dolomite dissolves initially and then precipitates due to availability of Mg++ ions from the dissolution of illite. The Ca++ ions released from the dissolution of anorthite and dolomite aid in the precipitation of calcite. Quartz and kaolinite precipitate due to the continuous availability of silicate and Al+++ ions from the dissolution of illite. Figure 15 shows the amount of quartz in-place as well as the amount of quartz deposited after 1,000 years. The modeling results show that the amount of deposited quartz is insignificant compared with the amount in-place. A similar behavior was shown by other reactive minerals. In this numerical example, the geochemical reactions have an insignificant influence on rock porosity due to higher silica content considered in the chemical composition of the rock.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure 14: Amount of mineral dissolved and deposited after 1,000 years.

Figure 15: Amount of quartz in-place (blue line) and deposited (red line) due to geochemical reactions.
4.2.2 Pressure Response

Figure 16 shows the brine density, the initial fluid pressure, and the changes in fluid pressure caused by CO$_2$ injection for the coupled fluid flow and geomechanics model when geochemical reactions were considered. The CO$_2$ was injected at a rate of 1,000 metric tonnes per day for 25 years. In the coupled fluid flow and geomechanics model with geochemical reactions, density of formation brine is a function of salinity. Results also show that the magnitude of fluid pressure change at the end of CO$_2$ injection period was small. The change in reservoir fluid pressure decays rapidly with time during the post-injection period.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure 16: Modeling results of coupled fluid flow and geomechanical model when geochemical reaction were considered.

(a) Brine density (lb/ft³)

(b) Initial fluid pressure (psi)

(c) Changes in fluid pressure caused due to CO₂ injection (psi)
4.2.3 Ground Response

Figure 17 shows the computed vertical displacements (ground uplift) at various time periods caused due to CO\textsubscript{2} injection. The maximum computed vertical displacement is about 0.039 in. (0.10 cm) after 25 years of injection in the coupled fluid flow and geomechanics model when geochemical reactions were considered. The magnitudes of ground displacement are small due to small changes in fluid pressure during injection.

Figure 17: Computed vertical ground displacement at various time periods.
5. LARGE-SCALE CO₂ INJECTION INTO A SALINE AQUIFER WITH COUPLED FLUID FLOW AND GEOMECHANICAL MODELS WITH GEOCHEMICAL REACTIONS

Modeling of large-scale CO₂ injection in the range of 5.511 to 11.02 million short tons per year (5 to 10 million metric tonnes per year) was carried out for 50 years to investigate the time-dependent influence of geochemical processes on the geomechanical response of the overburden. Two hypothetical large-scale CO₂ injection scenarios were considered to examine the extent of CO₂ migration, pressure response, and vertical ground displacements over a long-term period (1,000 years). Coupled multiphase fluid flow and geomechanical models with geochemical reactions were constructed similar to the models reported in previous sections of this report. The model geometry consists of an overburden layer, a tight caprock layer, a reservoir layer and an underburden layer as shown in Figure 18. The injection of CO₂ was carried out near the base of the reservoir with a single vertical injection well in the computational model.

An axisymmetric idealization was used in this study. The axisymmetric model consists of 230 grid-blocks in the radial-direction and 13 layers in the z-direction. Figure 19 shows the model geometry. A radial length of 492,126 ft (150,000 m) was used in this model. Such a large lateral extent was chosen to ensure that the boundary conditions have minimal effect on the geomechanical modeling results. Reservoir thickness was assumed to be 1,620 ft (494 m). The porosity and permeability of the reservoir was assumed to be 20% and 100 millidarcies (mD), respectively. The base of the model was fixed and lateral boundaries were constrained in the radial direction. The top surface of the model was assumed to move freely.
Two hypothetical large-scale CO₂ injection scenarios were considered to examine the extent of CO₂ migration, pressure response, and vertical ground displacements over a long-term period (1,000 years). The CO₂ injection was simulated for 50 years in all the scenarios with the primary injection rate constraint being 5.511 million short tons per year (5 million metric tonnes per year) and 11.02 million short tons per year (10 million metric tonnes per year). As a secondary constraint, the maximum bottomhole pressure of 4,562 psi (31,457 kPa) was assumed. The initial average reservoir pressure was assumed to be 3,340 psi (23,026 kPa) in the model, and the initial fluid pressure distribution considered for both the modeling cases is shown in Figure 20.

Geomechanical and geochemical properties were similar to those used in the coupled fluid flow and geomechanical model with geochemical reactions (discussed in previous sections). Modeling results of these cases are presented below.
5.1 **CASE 1: CO₂ INJECTION RATE OF 5 MILLION METRIC TONNES PER YEAR**

In this modeling scenario, CO₂ was injected with a primary injection rate constraint of 5.511 million short tons per year (5 million metric tonnes per year) and a secondary maximum bottomhole pressure of 4,562 psi (31,457 kPa). The injection period was assumed as 50 years. The change in reservoir pressure \( (p_0 - p) \) at the end of 50-year CO₂ injection is shown in Figure 21. The maximum change in reservoir pressure was about 266 psi (1,834 kPa), which corresponds to an increase of 8% above initial reservoir pressure. Negative signs in these figures indicate an increase in reservoir pressure due to CO₂ injection when compared to the initial reservoir pressure. The changes in reservoir pressure during the post-injection periods of 1 year and 50 years are shown in Figure 22 and Figure 23, respectively. The changes in reservoir pressure for other post-injection periods are shown in Appendix A. Post-injection results show that the reservoir pressure drops by 223 psi (1,537 kPa) (approximately 84% drop) at the end of 15 years. The drop in reservoir pressure after 50 years of post-injection is about 246 psi (1,696 kPa) (approximately 92.5% drop). These modeling results show how the reservoir pressure decays with time during the post-injection period.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO2 Storage in Saline Aquifers

Figure 21: Change in reservoir pressure due to CO2 injection at the end of injection period (50 years).

Figure 22: Change in reservoir pressure for post-injection period of 1 year.
Figure 23: Change in reservoir pressure for 50 years of post-injection period.

Figure 24 shows the vertical ground displacements at various times during CO₂ injection and post-injection period for the coupled multiphase fluid flow and geomechanical model with the consideration of geochemical reactions. The maximum computed vertical ground displacement (uplift) was about 0.59 in. (1.50 cm) after 50 years of CO₂ injection when geochemical reactions were considered in the model. Modeling results also show that the magnitude of maximum vertical ground displacement drops by about 90% after 50 years post-injection period. After 950 years of post-injection (i.e., total time period of 1,000 years), the vertical ground displacements were insignificant.
Figure 24: Computed vertical ground displacement during and post-injection.
5.2 CASE 2: CO₂ INJECTION RATE OF 10 MILLION METRIC TONNES PER YEAR

In this modeling scenario, CO₂ was injected with a primary injection rate constraint of to 11.02 million short tons per year (10 million metric tonnes per year) and a secondary maximum bottomhole pressure of 4,562 psi (31,457 kPa). The change in reservoir pressure caused due to CO₂ injection at the end of 50-year injection is shown in Figure 25. The maximum change in reservoir pressure was about 459 psi (3,164 kPa), which corresponds to an increase of 13.74% above initial reservoir pressure. The changes in reservoir pressure during the post-injection periods of 1 year and 50 years are shown in Figure 26 and Figure 27, respectively. The changes in reservoir pressure for other post-injection periods are shown in Appendix B. Post-injection results show that the reservoir pressure drops by 358 psi (2,468 kPa) (approximately 78% pressure drop) at the end of 15 years. The drop in reservoir pressure after 50 years of post-injection is about 421 psi (2,923 kPa) (approximately 92% pressure drop).

Figure 25: Change in reservoir pressure after 50 years of CO₂ injection.
Figure 26: Change in reservoir pressure for post-injection period of 1 year.

Figure 27: Change in reservoir pressure for post-injection period of 50 years.
Figure 28 shows the vertical ground displacements at various times during CO₂ injection and post-injection period for the coupled multiphase fluid flow and geomechanical models with the consideration of geochemical reactions. The maximum computed vertical ground displacement (uplift) was about 1.11 inches (2.82 cm) after 50 years of CO₂ injection. After 950 years of post-injection (i.e., total time of 1,000 years), the vertical ground displacements were insignificant.

Figure 29 shows the influence of geochemical reactions on the computed ground displacements. Results from the coupled fluid flow and geomechanics models with geochemical reactions indicate that the inclusion of geochemical reactions in the geomechanical models have very little influence on the computed vertical ground displacements during injection and post-injection periods in the problem considered in this study.

![Figure 28: Computed vertical ground displacement up to 50 years of post-injection.](image-url)
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure 29: Influence of geochemical reactions on computed ground displacements.
6. SUMMARY

The objective of this study is to investigate the influence of some geochemical process on the geomechanical response of the overburden during long-term CO₂ injection. In this study, 2-D, radially symmetric (i.e., axisymmetric), multiphase, and single-porosity models were constructed to study the influence of geochemical changes on the geomechanical response of the overburden over a long-term period (1,000 years). The model geometry consists of an overburden layer, a tight caprock, a sandstone reservoir formation and an underburden to represent a hypothetical CO₂ storage site. Two models were constructed to determine the influence of geochemical reactions or processes on rock properties (porosity and permeability) and the geomechanical response of the rock system. These two models consist of: 1) a geochemical model to determine the influence of geochemical reactions on rock properties such as porosity and permeability, and 2) a coupled fluid flow and geomechanics model with geochemical reactions to determine the influence of geochemical reactions on the geomechanical response of the system.

A hypothetical injection scenario was assumed for both the models where CO₂ was injected at a rate of 0.402 million short tons per year (0.365 million metric tonnes per year or 1,000 metric tonnes per day) for 25 years with a maximum bottomhole pressure of 4,351 psi (30,000 kPa). The model simulations were carried out for 1,000 years to examine the extent of CO₂ migration, geochemical processes such as mineral dissolution/precipitation, the change in rock properties, and pressure response. Modeling results show that the change in porosity due to geochemical reactions was insignificant. The reaction rate constants were then increased to investigate the influence of geochemical reaction rates on the rate of mineral dissolution/precipitation. The maximum change in the computed porosity was observed to be about 6% after 1,000 years. This change in porosity translates to a 30% change of the original porosity. In the coupled multiphase fluid flow and geomechanical model with geochemical reactions, a constant elastic modulus of 5.8e+06 psi (40 GPa) and a Poisson’s ratio of 0.25 was used for all rock formations. For the assumed values of material properties and geometric details, the increase in pressure due to CO₂ injection and the computed magnitudes of ground displacements can be considered insignificant.

Two hypothetical large-scale CO₂ injection scenarios (5 million metric tons per year and 10 million metric tons per year) were considered to examine the extent of CO₂ migration, pressure response and vertical ground displacements over a long-term period (1,000 years). The CO₂ injection was simulated for 50 years in all the scenarios with the primary rate constraint being 5.511 million short tons per year (5 million metric tonnes per year) and 11.02 million short tons per year (10 million metric tonnes per year). As a secondary constraint, the maximum bottomhole pressure of 4,562 psi (31,457 kPa) was assumed. The initial average reservoir pressure was assumed as 3,340 psi (23,026 kPa) in the model.

The maximum change in reservoir pressure when CO₂ was injected at a rate of 5.511 million short tons per year (5 million metric tonnes per year) was about 266 psi (1,834 kPa). The pressure increase of 266 psi (1,834 kPa) corresponds to an increase of 8% above hydrostatic pressure (initial reservoir pressure). The drop in reservoir pressure after 50 years of shutting down the CO₂ injection was about 246 psi (1,696 kPa) (~92.5% drop). In other words, the reservoir pressure increase due to CO₂ injection appears to decay towards the initial reservoir pressure. Geochemical reactions had no significant influence on rock porosity. The maximum computed vertical ground displacement (uplift) was about 0.59 in. (1.50 cm) after 50 years of CO₂ injection. Modeling results show that the magnitude of vertical ground displacements drops...
by about 90% after a post-injection period of 50 years. The computed magnitude of vertical
displacement after 1,000 years was insignificant.

In the case where CO₂ was injected at a rate of 11.02 million short tons per year (10 million
metric tonnes per year), similar pressure responses were observed. The maximum change in
reservoir pressure after 50 years of CO₂ injection was about 459 psi (3,164 kPa). The pressure
increase of 459 psi (3,164 kPa) corresponds to an increase of 13.74% above hydrostatic pressure
(initial reservoir pressure). The drop in reservoir pressure after 50 years of shutting down the
CO₂ injection was about 421 psi (2,923 kPa) (~92% drop). Geochemical reactions had no
significant influence on rock porosity. The maximum computed vertical ground displacement
(uplift) was about 1.11 in. (2.82 cm) after 50 years of CO₂ injection. Modeling results show that
the magnitude of vertical ground displacements drops by about 90% after a post-injection period
of 50 years. The computed magnitude of vertical displacement after 1,000 years was
insignificant.
7. REFERENCES


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Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO2 Storage in Saline Aquifers


Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers


Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

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APPENDIX A: RESULTS FOR CASE 1 (CO₂ INJECTION RATE OF 5 MILLION METRIC TONNES PER YEAR)

Figure A1: Change in reservoir pressure for post-injection period of 2 years.

Figure A2: Change in reservoir pressure for post-injection period of 3 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure A3: Change in reservoir pressure for post-injection period of 4 years.

Figure A4: Change in reservoir pressure for post-injection period of 5 years.
Figure A5: Change in reservoir pressure for post-injection period of 6 years.

Figure A6: Change in reservoir pressure for post-injection period of 7 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure A7: Change in reservoir pressure for post-injection period of 8 years.

Figure A8: Change in reservoir pressure for post-injection period of 9 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure A9: Change in reservoir pressure for post-injection period of 10 years.

Figure A10: Change in reservoir pressure for post-injection period of 11 years.
Figure A11: Change in reservoir pressure for post-injection period of 12 years.

Figure A12: Change in reservoir pressure for post-injection period of 13 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure A13: Change in reservoir pressure for post-injection period of 14 years.

Figure A14: Change in reservoir pressure for post-injection period of 15 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO2 Storage in Saline Aquifers

Figure A15: Change in reservoir pressure for post-injection period of 20 years.

Figure A16: Change in reservoir pressure for post-injection period of 25 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure A17: Change in reservoir pressure for post-injection period of 30 years.

Figure A18: Change in reservoir pressure for post-injection period of 35 years.
Figure A19: Change in reservoir pressure for post-injection period of 40 years.

Figure A20: Change in reservoir pressure for post-injection period of 45 years.
APPENDIX B: RESULTS FOR CASE 2 (CO₂ INJECTION RATE OF 10 MILLION METRIC TONNES PER YEAR)

Figure B1: Change in reservoir pressure for post-injection period of 2 years.

Figure B2: Change in reservoir pressure for post-injection period of 3 years.
Figure B3: Change in reservoir pressure for post-injection period of 4 years.

Figure B4: Change in reservoir pressure for post-injection period of 5 years.
Figure B5: Change in reservoir pressure for post-injection period of 6 years.

Figure B6: Change in reservoir pressure for post-injection period of 7 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure B7: Change in reservoir pressure for post-injection period of 8 years.

Figure B8: Change in reservoir pressure for post-injection period of 9 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO₂ Storage in Saline Aquifers

Figure B9: Change in reservoir pressure for post-injection period of 10 years.

Figure B10: Change in reservoir pressure for post-injection period of 11 years.
Figure B11: Change in reservoir pressure for post-injection period of 12 years.

Figure B12: Change in reservoir pressure for post-injection period of 13 years.
Figure B13: Change in reservoir pressure for post-injection period of 14 years.

Figure B14: Change in reservoir pressure for post-injection period of 15 years.
Influence of Geochemical Processes on the Geomechanical Responses of Overburden Strata during CO\textsubscript{2} Storage in Saline Aquifers

Figure B15: Change in reservoir pressure for post-injection period of 20 years.

Figure B16: Change in reservoir pressure for post-injection period of 25 years.
Figure B17: Change in reservoir pressure for post-injection period of 30 years.

Figure B18: Change in reservoir pressure for post-injection period of 35 years.
Figure B19: Change in reservoir pressure for post-injection period of 40 years.

Figure B20: Change in reservoir pressure for post-injection period of 45 years.
NRAP is an initiative within DOE’s Office of Fossil Energy and is led by the National Energy Technology Laboratory (NETL). It is a multi-national-lab effort that leverages broad technical capabilities across the DOE complex to develop an integrated science base that can be applied to risk assessment for long-term storage of carbon dioxide (CO₂). NRAP involves five DOE national laboratories: NETL, Lawrence Berkeley National Laboratory (LBNL), Lawrence Livermore National Laboratory (LLNL), Los Alamos National Laboratory (LANL), and Pacific Northwest National Laboratory (PNNL).

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